Calpine Solutions Exhibit 100
Witness: Kevin C. Higgins

BEFORE THE PUBLIC UTILITY COMMISSION OF THE STATE OF OREGON

In the Matter of PacifiCorp, dba	**)**	
Pacific Power	**)**	**Docket No. UE-323**
2018 Transition Adjustment	**)**	
Mechanism	**)**	

ERRATA

Opening Testimony of Kevin C. Higgins

on behalf of

Calpine Energy Solutions, LLC

June 9, 2017

OPENING TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this phase of the proceeding?

A. My testimony is being sponsored by Calpine Energy Solutions, LLC ("Calpine Solutions"). Calpine Solutions is a retail energy supplier that serves commercial and industrial end-use customers in 16 states, the District of Columbia, and Baja California, Mexico. Calpine Solutions serves more than 15,000 retail customer sites nationwide, with an aggregate load in excess of 4,500 MW. Calpine Solutions' retail customers are located in the service territories of 55 utilities. In Oregon, Calpine Solutions is currently serving customers in the service territories of Portland General Electric ("PGE") and PacifiCorp.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you ever testified before this Commission?

A. Yes. I have testified in twenty-five prior proceedings in Oregon, including eight PacifiCorp Transition Adjustment Mechanism ("TAM") proceedings, UE 307 (2017 TAM), UE 296 (2016 TAM), UE 264 (2014 TAM), UE 245 (2013 TAM), UE 227 (2012 TAM), UE 216 (2011 TAM), UE 207 (2010 TAM), and UE 199 (2009 TAM). I have also participated in six PacifiCorp general rate cases, UE 263 (2013), UE 246 (2012), UE 210 (2009), UE 179 (2006), UE 170 (2005), and UE 147 (2003), as well as the PacifiCorp Five-Year Opt-Out case, UE 267 (2013).

In addition, I have testified in five PGE general rate cases, UE 283 (2014), UE 262 (2013), UE 215 (2010), UE 197 (2008), and UE 180 (2006); the PGE Opt-Out case, UE 236 (2012); and the PGE restructuring proceeding, UE 115 (2001).

I also testified in the Investigation into PacifiCorp's Non-Standard Avoided Cost Pricing, UM 1802 (2017), the 2017 Inter-Jurisdictional Allocation proceeding, UM 1050 (2016) and Phase II of the Investigation into Qualifying Facility Contracting and Pricing, UM 1610 (2015).

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 190 proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also prepared affidavits that have been filed with the Federal Energy Regulatory Commission.

<u>Overview and Conclusions</u>

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses the calculation of the Schedule 294, 295, and 296 transition adjustments.

Q. What are the primary conclusions and recommendations in your testimony?

A. I offer the following primary conclusions and recommendations:

(1) The Schedule 294, 295, and 296 transition adjustments should be adjusted to reflect the value of freed-up Renewable Energy Certificates ("RECs"). Otherwise, direct access customers will unreasonably pay for Renewable Portfolio Standard ("RPS")-related resources twice: once from their Electricity Service

Supplier ("ESS") and a second time from PacifiCorp, which banks the RECs paid for by direct access customers for future use by cost-of-service customers.

PacifiCorp's proposal to recognize a credit for the value of freed-up RECs represents progress in concept when compared to the Company's previous opposition to any kind of REC credit for direct access customers. However, I disagree with the method used by the Company for valuing freed-up RECs. By valuing today's freed-up RECs strictly on the basis of the displacement of RECs that would be acquired by the Company in the distant future, i.e., 2028, direct access customers are unfairly disadvantaged. The Company's proposal to credit direct access customers with the greatly-discounted value of RECs displaced in the future does not adequately address the double payment for RPS-compliant service to which direct access customers are subject at the present time. Instead, this valuation is more reasonably made either using the price of RECs recently sold by PacifiCorp or the price of RECs being purchased by PacifiCorp through the 2016 Request for Proposals ("RFP") issued by the Company.

In the alternative, PacifiCorp could agree to transfer to the appropriate ESS the RECs for which its customers are paying PacifiCorp and receiving no credit. The ESS could then, in turn, retire the RECs for each compliance year and pass on that value to the customer. Or, in a variation on this concept, PacifiCorp could retire RECs either on behalf of direct access customers, or on behalf of a direct access customer's ESS, for the period corresponding to the calculation of a direct access customer's transition adjustment charges. These latter alternatives avoid the disputed issues in this case concerning the correct value to assign to the freed-up RECs, which has been the primary point of disagreement among the parties over this issue in past proceedings.

(2) In UE 296, and again in UE 307, I argued that in calculating the Schedule 296 Consumer Opt-Out charge, Schedule 200 costs should not be escalated in Years 6 through 10 as proposed by PacifiCorp. Rather, Schedule 200 costs used in this calculation should *decline* each year from Year 6 through Year 10 to reflect the decline in the Company's return on generation rate base attributable to the departed customers' loads, due to the effects of increased accumulated depreciation and amortization. The effects of this decline in return should be passed through to the Consumer Opt-Out charge in the Schedule 296 transition adjustment.

The Commission did not accept my argument on this point in UE 296 or UE 307. However, in the latter case, the Commission directed PacifiCorp to include in its next TAM filing a historical time series of fixed generation costs that are included in its direct access opt-out charge, broken down by its components, as a check on the reasonableness of the Company's forecasts. The information presented by PacifiCorp in response to the Commission's directive does not support the contention that the fixed costs of a fixed basket of generation assets is expected to increase at the rate of inflation, but rather supports my contention that such costs are likely to decline each year.

The Commission's order on this issue in UE 296 was appealed by Calpine Solutions to the Oregon Court of Appeals, and at the time of this testimony the issue remains before that court. In the event that this issue is reconsidered by the

Commission, the appropriate adjustments are presented in my testimony and exhibits in this docket.

The Transition Adjustment and Ongoing Valuation

Q. What is the purpose of retail direct access and transition adjustments under Oregon's direct access law?

A. Under a retail direct access program, the direct access customer continues to use the utility's distribution system but does not use the utility as its power supplier, but instead obtains energy from another supplier. Oregon's direct access law was initially enacted in 1999. In its findings supporting the legislation, the legislative assembly declared that "retail electricity consumers that want and have the technical capability should be allowed, either on their own or through aggregation, to take advantage of competitive electricity markets as soon as is practicable."[1] The direct access law requires that all nonresidential retail customers be allowed direct access to competitive markets by purchasing generation services from Commission-certified ESSs.[2] The law requires the Commission to implement rates that charge or credit the direct access customer an amount related to the utility's stranded generation assets that prevents "unwarranted shifting of costs."[3]

The direct access law is intended to allow nonresidential customers to have the option to control their generation supply if they prefer to purchase generation from sources other than the incumbent utility's portfolio. For

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[1] Or. Laws 1999, Ch. 865.
[2] *See* ORS 757.600(6), (16), -601(1), -649(1)(a).
[3] ORS 757.607(1), (2).

example, customers may wish to purchase more renewable energy than is available through PacifiCorp's cost-of-service portfolio. Alternatively, some customers may have a strong corporate preference for participating in the wholesale electricity market.

Q. By way of background, please summarize the status of direct access in PacifiCorp's service territory.

A. Fifteen years after the implementation of direct access in Oregon, the direct access program in PacifiCorp's service territory remains at very low participation levels. In my opinion, this low level of participation is due in large part to a transition adjustment regime that results in a negative value proposition for participating customers. PacifiCorp's shopping participation levels in 2016 were only 3.5% of eligible shopping load, far below the 15.7% participation rate in the PGE territory.[4] Oregon businesses continue to face material barriers to acquiring market-priced power in PacifiCorp's territory, despite the proximity to major wholesale trading hubs, and despite the plain objectives of the Oregon Legislature in enacting direct access legislation in 1999.[5]

Currently, PacifiCorp offers one-year, three-year, and five-year direct access programs. None of these programs has achieved significant participation levels. Prior to the 2016 shopping year, customers in the PacifiCorp territory could only choose between the one-year and three-year programs, pursuant to which the direct access customer pays the ESS for generation supply and

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[4] Source: Oregon Public Utilities Commission, Status Report: Oregon Electric Industry Restructuring (June 2016). *See* Exhibit Calpine Solutions/101, Higgins/1.

[5] ORS 757.601(1) provides that "[a]ll retail electricity consumers of an electric company, other than residential electricity consumers, shall be allowed direct access beginning on March 1, 2002."

continues to pay PacifiCorp for Schedule 200 generation costs, subject to a transition adjustment discussed later in my testimony. At the conclusion of the one-year or three-year term the customer is required to return to cost-of-service or elect a new one-year or three-year term. Under this regime, the customer never stops paying for PacifiCorp's generation resources.

PacifiCorp's five-year opt-out program was initiated for service commencing on January 1, 2016, after the Company was ordered to adopt such a program in Order No. 12-500. In that order, the Commission required PacifiCorp to file a tariff for a five-year opt out program that would allow a qualified customer to go to direct access and pay transition charges for the next five years, and then to be no longer subject to transition adjustments. After the conclusion of payments of five years of transition adjustments under the program, the customer would only pay PacifiCorp for distribution delivery service.

In contrast to the one-year and three-year programs, the five-year opt-out program, in theory, allows customers to migrate to 100% market prices for generation services (purchased from an ESS) without any remaining obligations to compensate PacifiCorp for generation resources it has acquired for bundled customers. PGE has had a five-year opt-out program for several years and it has been relatively successful. However, as I will discuss below, the structure of the PacifiCorp five-year opt-out approved by the Commission in UE 267 and UE 296 exacerbates the negative value proposition typically found in the Company's one-year and three-year programs. Consequently, despite the inherent appeal of a five-year opt-out program, the five-year opt-out program approved for PacifiCorp is not – and is unlikely to become – an economically viable proposition for most eligible customers. Consistent with this expectation, PacifiCorp indicated in its 1st Supplemental Response to Calpine Solutions Data Request 1.3.c.iii that only a single customer is enrolled in the five-year program.[6]

Q. What is your understanding of the purpose of the transition adjustment?

A. The purpose of the transition adjustment is to provide the appropriate credit or charge for customers who choose direct access service. The transition adjustment is applied either through Schedule 294, Schedule 295, or Schedule 296. Schedule 294 is applied to customers who choose a one-year direct access option, Schedule 295 is applied to customers who choose a three-year direct access option, and Schedule 296 is applied to customers who select the five-year opt-out that was authorized in UE-267.

PacifiCorp's transition adjustment calculation is a form of Ongoing Valuation as prescribed in OAR 860-038-0140. According to OAR 860-038-0005(41):

> Ongoing Valuation means the process of determining transition costs or benefits for a generation asset by comparing the value of the asset output at projected market prices for a defined period to an estimate of the revenue requirement of the asset for the same time period.

The logical premise behind Ongoing Valuation is to credit or charge direct access customers the difference between market prices and cost-of-service rates. The design logic in this approach places customers in an economically "break even" position with respect to the choice of direct access service; that is, if market prices are below cost-of-service rates at the time the transition adjustment is

[6] See Exhibit Calpine Solutions/102, Higgins/3, which contains PacifiCorp's 1st Supplemental Response to Calpine Solutions Data Request 1.3.c.iii.

calculated, the direct access customer is charged the difference via the transition adjustment. Conversely, if market prices are *above* cost-of-service rates, the direct access customer is *credited* the difference via the transition adjustment.

The corollary to this design logic is that it holds non-participating customers harmless, as the utility, which buys and sells billions of kilowatt-hours over the course of a year, should be able to dispose of the energy freed up by direct access through market transactions. In the case of PacifiCorp, the transition adjustment analysis consists of evaluating the impact of 25 MW of direct access load on a 10,000 MW system in the calculation of Schedules 294 and 295, and 50 MW of direct access load in the calculation of Schedule 296.

Q. Please explain how direct access can be viable if the design logic of Ongoing Valuation places direct access customers in an economically break even position.

A. For customers who attempt to select direct access service on a year-to-year basis, the Ongoing Valuation approach indeed makes direct access a tenuous value proposition. A one-year direct access selection may be economically viable in certain circumstances, such as, for example, if some market movement occurs during the shopping window, after the transition adjustment has been set. Additionally, other customers may wish to purchase more renewable energy than is available through PacifiCorp's cost-of-service portfolio. Alternatively, some customers may have a strong corporate preference for participating in the market, despite the barrier of contending with a "break even" transition adjustment design. But in general, the year-to-year "break even" model is not particularly attractive for customers. In Oregon, the only direct access program that has shown signs of sustained success is PGE's five-year opt-out program, in which customers pay PGE's Ongoing Valuation transition adjustment for five years, and then migrate fully to market prices (with no further transition adjustments). As I noted above, pursuant to the Commission's order in UE-267, PacifiCorp implemented a five-year opt-out program effective January 1, 2016. However, the design of the transition adjustment for the PacifiCorp five-year opt-out differs in important respects from the PGE program and exacerbates the negative value proposition generally found in PacifiCorp's one-year and three-year programs. Consequently, in its current form, the PacifiCorp five-year opt-out program is unlikely to be viable for most eligible customers.

<u>Calculation of the One-Year and Three-Year Transition Adjustments (Schedules 294 and 295)</u>

Q. What is the basic structure of PacifiCorp's current charges for generation services?

A. PacifiCorp assesses rates for generation services to cost-of-service customers on two different rate schedules. First, the Company charges customers for its net power costs in Schedule 201, which includes long-term power purchase contracts, short-term market purchases, and fuel for power generation. Second, PacifiCorp charges customers for all other generation costs, including the costs of its rate-based generation investments, in Schedule 200.

Q. How is PacifiCorp's transition adjustment mechanism for Schedules 294 and 295 calculated?

A. PacifiCorp's transition adjustment charges (or credits) direct access customers the difference between PacifiCorp's net power cost (as reflected in Schedule 201) and the estimated market value of the electricity that is freed up when a customer chooses direct access service.[7] This is calculated by subtracting the former from the latter, after adjusting the latter for line losses to reflect its value at the point of retail delivery. If the result is a positive number, the difference is applied as a credit to the direct access customer. If the result is a negative number, the difference is applied as a charge to the direct access customer.

Q. If Schedule 294 or 295 is a credit, does that mean that PacifiCorp's generation costs are less expensive than the market and that direct access customers are being paid to leave cost-of-service rates?

A. No. PacifiCorp direct access customers must continue to pay for the Company's fixed generation costs through Schedule 200. A Schedule 294 credit simply means that the Company's *net power costs* are less than market prices. Only if the Schedule 294 credit were greater than the Schedule 200 charge could it be accurate to state that direct access customers were being "paid" to leave cost-of-service rates. That is far from the case today. For example, PacifiCorp's sample 2018 Schedule 294 rate for Schedule 48-P customers is an average credit

[7] Direct access customers in PacifiCorp's service territory already pay for the Company's fixed generation costs through Schedule 200. Thus, the transition adjustment is calculated by subtracting *net power costs* from the value of freed-up energy rather than subtracting *total generation costs* from the value of freed-up energy. Calculating the transition adjustment in this manner is logically equivalent to subtracting total generation costs from the value of freed-up energy while *not* charging direct access customers for Schedule 200.

of $8.07/MWh during Heavy Load Hours and an average credit of $5.58/MWh during Light Load Hours,[8] while the average Schedule 200 charge for these customers in 2018 is projected to be $28.63/MWh.[9] Thus, the Schedule 200 charge is far greater than the transition adjustment credit, meaning that the direct access customer makes a net payment to PacifiCorp for generation resources that the customer does not use.

Q. Please continue with your explanation of how PacifiCorp's Schedule 294 and 295 transition adjustment mechanism is calculated.

A. The transition adjustment is calculated using PacifiCorp's GRID model. According to PacifiCorp's tariff, the estimated market value of the electricity that is freed up when a customer chooses direct access service is determined by running two system simulations – one simulation <u>with</u> PacifiCorp serving the direct access load and one simulation with the Company <u>not</u> serving the direct access load. At the present time, for the Schedule 294 one-year and Schedule 295 three-year programs, these simulations are run assuming direct access occurs in 25 MW decrements, which are shaped using the load shape of the rate schedule being analyzed for purposes of determining its Schedule 294 or 295 credit (or charge). The difference between the two scenarios is used to calculate the impact on PacifiCorp's total system, which is then used to determine the "weighted

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[8] Inclusive of PacifiCorp's proposed REC credit, discussed below.

[9] Sources: The average Schedule 294 credits are derived from PacifiCorp's Response to TAM Support Set 3. See Exhibit Calpine Solutions/102, Higgins/1 for the relevant source material. The average Schedule 200 rate for 2018 is provided by PacifiCorp in the Confidential Attachment 1.7-1 to PacifiCorp's Response to Calpine Solutions Data Request 1.7. Certain non-confidential information from this attachment is presented in Exhibit Calpine Solutions/103. *See* Exhibit Calpine Solutions/103/Higgins/3 for the Schedule 200 charge referenced in my testimony. PacifiCorp consented to my use of this figure as non-confidential in this testimony.

market value of the energy" freed up due to direct access.[10] The weighted market value of the energy is then compared to the customer's price under Schedule 201 to determine the Schedule 294 or 295 credit (charge).

Q. Does PacifiCorp's Ongoing Valuation calculations for Schedules 294 and 295 result in a "break even" proposition for customers?

A. Typically not. I explained in Docket UE 264 that this approach does not adhere strictly to the definition of Ongoing Valuation articulated in OAR 860-038-0005(41). Ongoing Valuation requires that transition costs or benefits for a generation asset be determined by comparing the value of the asset output at projected *market prices* to an estimate of the revenue requirement of the asset. PacifiCorp's use of the GRID model to calculate transition costs does not produce a valuation based exclusively on projected market prices as required in the OAR, but a valuation that is based on a blend of market prices and avoided costs of thermal generation costs. Because the incremental cost of PacifiCorp's thermal generation is typically less than market prices, blending market prices and the Company's thermal costs has historically produced a lower valuation of freed-up energy than would occur if market prices alone were used for this purpose. Because the value of freed-up energy is a credit against the cost-of-service price for direct access customers in the calculation of Schedules 294 and 295, using a lower price for this purpose increases the transition adjustment charge (or alternatively, reduces the transition adjustment credit), all other things being equal. Indeed, because shopping customers must pay an ESS market prices for

[10] *See* PacifiCorp Tariff, Schedule 294, p. 1.

power, if the value of freed-up energy used in the calculation of the transition adjustment is less than the actual market price direct access customers pay, then it creates a negative value proposition for year-to-year shoppers rather than the break-even proposition inherent in the logic of Ongoing Valuation. I note that in the current low market price environment, the last two TAMs have been an exception to this historical pattern, in that the GRID-calculated costs for 2017 and 2018 are greater than projected market prices on average. Whether this exception represents the start of a new pattern or a short-time departure from the general trend remains to be seen.

Q. Have refinements been developed to mitigate the impact of including thermal costs in the calculation of Schedules 294 and 295?

A. Yes. In UE-199 (2009 TAM), a Stipulation approved by the Commission in Order No. 08-543 modified the valuation of the thermal generation assumed to be backed down due to direct access by providing for a partial weighting using market prices. Specifically, the parties agreed as follows:

> 15. <u>Transition Adjustment</u>: The Parties agree to modify the calculation of the Transition Adjustment for direct access in two ways: (1) the Company will relax the market cap limitations in the GRID model by 15 MW at Mid-Columbia and 10 MW at COB to determine the value of the freed up power; and (2) any remaining monthly thermal generation that is backed down for assumed direct access load will be priced at the simple monthly average of the COB price, the Mid-Columbia price, and the avoided cost of thermal generation as determined by GRID. The monthly COB and Mid-Columbia prices will be applied to the heavy load hours or light load hours separately. The existing balancing account mechanisms will remain in effect.

The partial weighting using market prices was implemented pursuant to the second provision quoted above. While this provision mitigates the negative value proposition typically faced by direct access customers in the PacifiCorp territory, it does not eliminate it.[11]

Q. Has this second provision been applied continuously since its initial adoption in UE-199?

A. Yes. PacifiCorp has continued to apply this provision in each TAM proceeding since it was initiated in 2009 and continues to apply it in the 2018 TAM.[12]

Q. Are there other elements in the TAM calculation that contribute to the negative value proposition?

A. Yes. In Docket UE 264, to address the problem of negative bias in the calculation of the PacifiCorp TAM, I recommended recognizing a BPA Point-to-Point transmission credit to remedy a structural impediment to the pricing of direct access service associated with the need for an ESS to obtain wheeling from BPA to reach the PacifiCorp service territory from the Mid-C trading hub.

Q. Are you advocating for adoption of a BPA Point-to-Point transmission credit in this proceeding?

A. No. Although I continue to believe this modification is appropriate, I am not advocating for this change in this proceeding because it was not adopted by the Commission in UE 264.

Q. In UE 296 and UE 307, you recommended that the Schedule 294 and 295 TAM calculations be modified to capture the effects of Oregon's RPS on the transition adjustment. Why did you make that recommendation?

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[11] I demonstrated this point in UE 264. See Rreply Testimony of Kevin C, Higgins, pp.16-21.

[12] This is confirmed in PacifiCorp Response to Calpine Solutions Data Request 1.1, included in Exhibit Calpine Solutions/102, Higgins/2.

A. The Oregon RPS is applicable to both cost-of-service and direct access customers. When direct access customers purchase power from an ESS, the energy provided by the ESS must meet RPS requirements, which as applicable to PacifiCorp service territory requires that 15% of supply come from qualifying renewable electricity in calendar years 2018 and 2019, 20% of supply come from qualifying renewable electricity in calendar years 2020 through 2024, and 27% in calendar years 2025 through 2029.[13] At the same time, direct access customers pay for the renewable energy that PacifiCorp has acquired to meet the RPS for its cost-of-service customers. In the case of the five-year program, for example, customers opting out later this year would pay projected costs of the existing portfolio of RPS-compliant resources in Schedules 200 and 201 through the year 2027. In paying both the ESS and PacifiCorp for RPS power, direct access customers are paying twice to meet RPS requirements, a circumstance that I believe is unreasonable and inequitable.

Q. How do direct access customers pay PacifiCorp for RPS requirements?

A. PacifiCorp recovers its RPS-related costs both through Schedule 200, through which the fixed costs of utility-owned renewable generation are recovered, and Schedule 201, through which power purchases of RPS-eligible resources are recovered.[14] For each MWh of electric energy produced by the RPS-complaint resources in Schedules 200 and 201, the resource also produces a REC. As I discussed above, direct access customers are charged directly for Schedule 200 and also pay for the difference between Schedule 201 costs and the

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[13] ORS 469A.052(1), 469A.065.

[14] This fact was established in UE 296. See PacifiCorp Response to Noble Solutions Data Request 1.11, included in Exhibit Noble Solutions/102, Higgins/7 in that docket.

value of the freed-up power, as calculated through the transition adjustment calculation. In addition, direct access customers on the one-year and three-year programs pay for Schedule 203, the Renewable Resource Deferral Supply Service Adjustment, which recovers the costs of RECs that were purchased following PacifiCorp's 2016 RFP, which funds the acquisition of incremental RPS-eligible resources. Further, in this proceeding, PacifiCorp is proposing that new customers entering the five-year program pay for Schedule 203 as well.[15]

Q. When a customer switches to direct access and acquires its RPS resources from its ESS, what happens to PacifiCorp's RPS requirement?

A. When a customer switches to direct access, PacifiCorp's RPS obligation is reduced proportionately. Thus, just as the electric energy is freed up when the customer moves to direct access, the RECs are also freed up. The freed-up RECs are banked for future use by PacifiCorp's cost-of-service customers.[16]

Q. Are direct access customers currently compensated for the value of the RECs procured to serve their load by PacifiCorp or otherwise allowed to recognize the benefits of those RECs PacifiCorp procured on their behalf prior to the direct access election?

A. No. The current transition adjustment mechanisms recognize and credit the customer for the value of the freed-up energy, through the GRID analysis I described above. However, the current regime provides no credit for the value of the freed-up RECs, even though it indisputable that PacifiCorp's portfolio of

[15] *See* Direct Testimony of Michael G. Wilding, pp. 35-36.
[16] *See*, p. 32.

RPS-compliant resources paid for by the direct access customer will generate RECs.

Q. Do you believe the status quo is reasonable?

A. No. It is not reasonable for direct access customers to be required to pay twice to meet the RPS requirements, and effectively subsidize the cost of RECs that are banked for future use by cost-of-service customers.

Q. What remedy did you recommend to address this concern in UE 307?

A. In UE 307, I identified three different valuation approaches, any one of which I believe is reasonable to be used in this docket to value RECs that are freed up by direct access. They are:

(1) <u>Value freed-up RECs based on the value of PacifiCorp REC sales</u>. PacifiCorp actively sells RECs that are not required to meet state RPS requirements. The revenues from these sales are credited to customers in non-RPS states such as Utah and Wyoming, and the valuations of the REC sales are reported in those states in the ordinary course of ratemaking. The sold RECs are classified by PacifiCorp in proceedings in those states either as "structured" or "unstructured," depending on their attributes, which correspond generally to the "bundled" and "unbundled" attributes recognized in the Oregon RPS.[17] For purposes of the TAM, the price of unstructured RECs, prorated for the proportion of resources that must be RPS-eligible (i.e., 15% at the current time), could be added to the weighted average market price of energy freed-up by direct access.[18]

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[17] A bundled REC includes the underlying electricity for which the REC was issued, whereas an unbundled REC generally does not. *See* ORS 469A.005 (4), (14).

[18] I note that this approach to valuation does not depend on an assumption that PacifiCorp must sell freed-up RECs. I recognize at the outset that PacifiCorp banks freed-up RECs for the purpose of the Oregon

(2) Value freed-up RECs using the prices paid by PacifiCorp to acquire RECs through its 2016 RFP. The RFP was issued to help PacifiCorp meet its RPS obligations. The Company is no longer simply banking excess RECs but is also actively acquiring RECs for future use. The price PacifiCorp is paying third parties for the additional RECs necessary to meet the RPS standard provides direct information regarding the value of RECs freed up by direct access customers.

(3) For the period during which a customer is paying transition charges to PacifiCorp, PacifiCorp could agree to transfer to the ESS the RECs for which the ESS's direct access customers are paying PacifiCorp and receiving no credit. The ESS could then, in turn, retire the RECs for each compliance year and pass on that value to the customer. Another option that would achieve the same result without requiring any transactions between the ESS and PacifiCorp would be for PacifiCorp to simply retire the freed-up RECs on behalf of the direct access customer or the ESS; this would allow the customer to avoid paying the ESS for RPS compliance. These approaches resolve the inequity of double RPS payments by direct access customers by directly transferring the RECs, making the REC valuation exercise unnecessary and thereby eliminating the major point of contention between the parties on this issue.

Q. What did the Commission determine regarding your proposed approaches in UE 307?

RPS. Rather, this approach merely recognizes the fact while PacifiCorp may bank RECs for the purpose of the Oregon RPS, the Company also regularly *sells* RECs. The value of the Company's REC sales can be used to value the banked RECs for the purpose of incorporating the value of freed-up RECs in the transition adjustment.

A. The Commission declined to adopt any of my recommended approaches, but directed PacifiCorp, Staff, and the parties to further discuss REC valuation as part of a workshop, with a focus on the potential benefits that may derive at the time PacifiCorp must take substantive action to comply with its RPS targets.

Q. Did you participate in the workshop on behalf of Calpine Solutions?

A. Yes, I did.

Q. Did the parties to the workshop reach consensus on the best approach to REC valuation?

A. No. However, some progress was made in that PacifiCorp has agreed in this case to include some credit for RECs freed-up by direct access customers in the 2018 TAM. The Company's proposal is presented in the Direct Testimony of Michael G. Wilding.[19]

Q. Please describe PacifiCorp's proposal for valuing RECs freed up by direct access.

A. Because RECs freed up from direct access are banked for future use, the Company reasons that the impact of a lower RPS compliance requirement due to direct access is to extend the future date at which PacifiCorp will need to acquire new resources or RECs to meet its compliance requirements. Therefore, PacifiCorp proposes to value freed-up RECs by calculating the future value associated with the delay in the timing of the company's RPS compliance shortfall. The credit would be applied to the transition adjustment and would remain fixed during the time period covered by the direct access program.

[19] Direct Testimony of Michael G. Wilding, pp. 30-36.

According to Mr. Wilding, the first year in which the Company has a compliance shortfall is 2028. To calculate the credit, PacifiCorp applied the purchase price for RECs that are deliverable in 2028 to the amount of freed-up RECs. That savings is discounted back into 2018 dollars and applied to the volume of direct access load, which is then levelized over the period in which the customer elects direct access.[20]

Q. What is your assessment of PacifiCorp's REC valuation proposal?

A. PacifiCorp's proposal represents progress in concept when compared to the Company's previous opposition to any kind of REC credit for direct access customers. However, I disagree with the method used by the Company for valuing freed-up RECs. By valuing today's freed-up RECs strictly on the basis of the displacement of RECs that would be acquired by the Company in the distant future, i.e., 2028, direct access customers are unfairly disadvantaged. Direct access customers must pay their ESS for RPS-compliant service *today*, and are also paying PacifiCorp for a pro rata share of the Company's RPS-compliant service at *today's rates* – not a discounted rate based on costs eleven years in the future. The Company's proposal to credit direct access customers with the greatly-discounted value of RECs displaced in the future does not adequately address the double payment for RPS-compliant service to which direct access customers are subject at the present time.

The Commission's requirement that PacifiCorp bank excess RECs for future use was not directed specifically to RECs feed-up by direct access customers; further, it is unlikely that the Commission intends for direct access

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[20] *See* Direct Testimony of Michael G. Wilding, pp. 32-34.

customers to subsidize future cost-of-service customers by requiring direct access customers to provide surplus RECs to cost-of-service customers at a significant discount. Rather, it appears that direct access customers are simply being collaterally harmed as a side effect of the Commission's broader policy of requiring PacifiCorp to bank surplus RECs. This harm can be rectified by simply crediting direct access customers with today's value of RECs, either by valuing them using the price of RECs recently sold by PacifiCorp or the price of RECs recently purchased by PacifiCorp through its RFP.

Q. Do you also continue to recommend an option in which PacifiCorp simply transfers to the direct access customer's ESS the direct access customer's pro rata share of RECs, so that the ESS could retire the RECs for each compliance year and pass on that value to the customer?

A. Yes. This option deals with the issue head-on by allowing direct access customers to get their fair share of the value from the RPS-compliant resources for which they are paying the Company. It also avoids any controversy over REC valuation. It may make sense to amend or clarify the Commission's RPS compliance rules to facilitate the retirement of ESS RPS obligations through this type of direct transfer. Additionally, in response to concerns PacifiCorp raised in the workshops regarding engaging in transactions to transfer RECs to the ESSs, PacifiCorp could avoid any need to engage in such transactions by simply retiring the RECs on behalf of the customer or the ESS through PacifiCorp's Western Renewable Energy Generation Information System ("WREGIS") account.

PacifiCorp has presented no reason why it is unable to retire the freed-up RECs on behalf of the customer or the ESS.

Q. Are there precedents in Oregon regarding the ability of a utility to retire RECs on behalf of another party?

A. Yes. PacifiCorp already retires RECs on behalf of customers enrolled in their Blue Sky program, Schedule 272, which is explained as follows in the tariff:

> RECs procured pursuant to this Schedule will be either (i) delivered by Company, at Company's expense, to Consumer's registered Western Renewable Energy Generation Information System (WREGIS) account (as set forth in a written contract between Company and Consumer and approved by the Commission), or (ii) deposited into a WREGIS account maintained by Company and retired on behalf of Consumers (except with respect to RECs generated from Qualifying Initiatives as set forth above in this Schedule). All costs associated with transferring, retiring, administering or otherwise managing RECs within Consumer WREGIS accounts shall be borne by Customer.

Another example is described in Order No. 15-327, in which the Commission approved a sale-lease-back arrangement through which PGE would retire RECs from a solar facility on behalf of Portland Public Schools.[21]

Yet another example occurs in Order No. 15-405, in which the Commission specifically required that if a utility offered a Voluntary Renewable Energy Tariff, "Any RECs associated with serving participants must be retired by or on behalf of participants, unless the participants consent to RECs being retired by the utility or the developer." [22]

There and other examples demonstrate that this concept is well established and workable.

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[21] *See* UP 324, Order No. 15-327 at 1; Appendix A at 5.
[22] *See* UM 1690, Order No. 15-405 at 1.

Q. Please summarize your recommendations regarding the treatment of RPS-eligible resources in the calculation of the Schedule 294 and 295 transition adjustment.

A. I recommend that direct access customers be credited with the value of RECs freed-up due to direct access in the calculation of the Schedule 294 and 295 transition adjustments. The value of a freed-up REC, multiplied by the RPS percentage requirement (e.g., 15% in 2018), should be added to the weighted average market price of freed-up energy in the TAM calculation. For the purpose of this calculation, this valuation could be made either using the price of RECs recently sold by PacifiCorp or the price of RECs recently purchased by PacifiCorp through its RFP. I note that this is a conservative valuation because it effectively only credits the customer for the value of unbundled RECs while in fact the generation resources freed-up by the customer's direct access election generate a substantial amount of more valuable bundled RECs.

In the alternative, PacifiCorp could agree or be required to transfer to the direct access customer's ESS the customer's pro rata share of RECs, or simply retire the RECs on the customer's or ESS's behalf, enabling the value of RECs to be passed on to the direct access customer without the need to value them in this proceeding or future proceedings.

Calculation of the Five-Year Transition Adjustment (Schedule 296)

Q. How is PacifiCorp's transition adjustment mechanism for Schedule 296 calculated?

A. PacifiCorp's sample calculation of Schedule 296 is provided in Confidential Attachment 1.7-1 in Response to Calpine Solutions Data Request 1.7. I have provided a non-confidential excerpt from this data response that summarizes PacifiCorp's sample calculation for Schedules 30-S and 48-P in Exhibit Calpine Solutions/103, Higgins/1-3.[23]

Schedule 296 consists of two major parts: (1) a five-year transition adjustment component that structurally is nearly identical to the calculation of the Schedule 294 and 295 transition adjustments, and (2) a Consumer Opt-Out component, which brings forward into Years 1 through 5 the projected Schedule 200 costs for Years 6 through 10, net of projected net power costs savings attributed to the departed opt-out load. PacifiCorp proposes to apply the REC credit it has calculated in this docket to this component.

In addition to the Schedule 296 charge, the customer must also pay PacifiCorp the base Schedule 200 charge for five years, which may be updated in each rate case during that period.

From the effective date of the opt-out election forward, the customer also pays charges for the generation and delivery that the customer will use to serve its load, which includes payments to an ESS for the generation and to PacifiCorp for delivery service under an applicable delivery service tariff.

Q. Does Schedule 296 result in a negative value proposition for customers during the five-year opt-out period?

[23] PacifiCorp consented to my use of these excerpts of its discovery response as non-confidential in this testimony.

A. Yes. The negative value proposition derives from two sources. The first source is a result of calculating the transition adjustment using the GRID model, further exacerbated by the absence of a credit for BPA PTP transmission, as I noted above in relation to Schedules 294 and 295 and previously discussed in detail in UE 264 and UE 267.[24] The second source is the Consumer Opt-Out charge, which brings forward projected costs from Years 6 through 10 and recovers them in Years 1 through 5. It is self-evident that *even if* the transition adjustment itself were a break even proposition (as intended per the Ongoing Valuation approach) the addition of costs from future years to an otherwise break even transition adjustment would create a negative value proposition in the amount of the additional charge, i.e., in the amount of the Consumer Opt-Out charge itself.

So, for example, according to PacifiCorp's sample calculation, in Year 1 of the five-year opt-out, a Schedule 48-P customer would pay an average of $28.63/MWh for Schedule 200, while receiving a Transition Adjustment credit of $2.99/MWh, for a net charge of $25.64/MWh, prior to considering the Consumer Opt-Out charge.[25] Conceptually, under ongoing valuation, this $25.64/MWh net charge is *intended* to produce a "break-even" value proposition for the direct access customer relative to cost-of-service rates, after taking into account the customer's purchase of market power. But, in addition, the five-year opt-out

[24] As I noted above, the last two TAMs are exceptions to this historical result.
[25] This information is presented in Exhibit Calpine Solutions 103, Higgins/3, which is a non-confidential excerpt of PacifiCorp's confidential response to Calpine Solutions' Data Request 1.7. PacifiCorp consented to use of the excerpt in the exhibit and figures therein in this testimony as non-confidential information.

customer would pay a Consumer Opt-Out charge of $14.18/MWh (excluding REC credits).

Based on these sample charges, a participating customer using 100,000 MWh of energy per year (roughly the size of a 15 MW customer) would pay PacifiCorp $3,982,000 per year in Year 1 for transition costs (inclusive of Schedule 200 and the Consumer Opt-Out charge)[26] *in addition* to paying an ESS for market-priced power.

Q. You indicated that, structurally, the five-year transition adjustment component of Schedule 296 is nearly identical to the calculation of the Schedule 294 and 295 transition adjustments. In what ways does it differ from the Schedule 294 and 295 calculation?

A. Aside from the obvious fact that it is calculated for five years (instead of one or three), the transition adjustment component of Schedule 296 is calculated assuming 50 MW of direct access load rather than 25 MW, as is assumed for Schedules 294 and 295. The five-year opt-out customers will also pay Schedule 200 rates for each of the first five years of the opt-out period. In this manner, Schedule 296 is comparable to Schedule 294. Schedule 295 is slightly different, in that three-year opt-out customers pay for *projected* Schedule 200 costs, rather than contemporaneous Schedule 200 costs. Otherwise, the Schedule 296 transition adjustment component is calculated in a manner that is identical to the Schedule 294 and 295 transition adjustments.

[26] ($25.64/MWh + $14.18/MWh) x 100,000 MWH = $3,982,000.

Q. In your opinion, should the transition adjustment component of Schedule 296 be adjusted to reflect the value of freed-up RECs, as you propose for Schedules 294 and 295?

A. Yes. The rationale for recognizing this value in Schedule 296 is the same as for Schedules 294 and 295. In the case of Schedule 296, the REC valuation should be updated annually for Year 1 through Year 5 and should reflect the then-current proportion of RPS-eligible resources that is required. In addition, for Years 6 through 10, a projected value for freed-up RECs should be included as a credit in the calculation of the Consumer Opt-Out charge, combined with the relevant RPS requirement percentage.

In the alternative, as I discussed above, PacifiCorp could agree or be required to transfer to the direct access customer's ESS the customer's pro rata share of RECs, or simply retire those RECs on the customer's or the ESS's behalf, thereby passing on that value to the direct access customer. This transfer should occur during the same 10-year-period over which the Consumer Opt-Out charge is calculated for a given customer. After that time, the ESS would be responsible for meeting the RPS requirements for the customer for as long as the customer continues to take direct access service.

Q. Has PacifiCorp agreed that a REC credit should be applied to Schedule 296?

A. Yes. However, the Company's method for calculating the credit is based on the value of RECs many years in the future, discounted to the present, as I discussed above. Consequently, the Company's approach inequitably undervalues the RECs that are being freed-up by direct access customers today.

Q. You stated that in UE 296 and UE 307 you proposed a modification to the calculation of the Consumer Opt-Out charge. What did you recommend in those dockets?

A. I recommended two refinements to the calculation. PacifiCorp's calculation of the Consumer Opt-Out charge is based on projected Schedule 200 costs for Years 6 through 10. Under PacifiCorp's approach, these projected costs are simply current Schedule 200 rates escalated at an assumed rate of inflation. However, I argued that it is not reasonable for Schedule 200 costs to be escalated for Years 6 through 10 as part of this calculation, because the five-year opt-out customer will have already departed cost-of-service rates five years prior, and *incremental* fixed generation costs incurred during Years 6 through 10 should not be incurred on the departed customer's behalf. Rather, the opt-out charge for Years 6 through 10 should be limited to the generation investment that had been built for the departed customer's benefit. At the maximum, this would extend to the five-year planning horizon following the customer's departure (i.e., Years 1 through 5 of the opt-out period). This allowance for escalation of costs in the first five years is very conservative because it assumes that PacifiCorp cannot unwind prior commitments for five full years after the date of the opt-out election.

My first refinement to the Consumer Opt-Out charge was that Schedule 200 costs should not be escalated in Years 6 through 10; since incremental generation expenditures are not incurred on departed customers' behalves, it is not reasonable to assume increased Schedule 200 costs for departing customers beyond the projected Year 5 Schedule 200 price.

The second refinement is an extension of this argument. Not only should Schedule 200 costs not be escalated for the purpose of determining the Consumer Opt-Out charge, these costs should in fact *decline* each year from Year 6 through Year 10 to reflect the decline in the Company's return on generation rate base attributable to the departed customers' loads, due to the effects of increased accumulated depreciation and amortization. That is, as I just discussed, the portfolio of generation resources acquired to meet the departed customer's load should not be increased after Year 5. Once the portfolio of assets is "frozen" for the purposes of this calculation, the revenue the Company earns from its return on these assets properly will decline each year as a portion of those assets is depreciated and amortized. This treatment is consistent with basic ratemaking principles, which provide that a utility's return is earned on its net plant, reflecting the removal of accumulated depreciation and amortization from rate base. The effects of this decline in return should be passed through to the Consumer Opt-Out charge.

Q. Did the Commission accept your recommendation?

A. No. In UE 296, the Commission rejected my recommendation, stating:

> We have previously addressed the claim that the customer opt-out charge should be reduced to reflect a more accurate estimate of fixed generation costs. Noble Solutions has produced no new evidence or argument to persuade us to change our positon (sic). *PacifiCorp explains that incremental generation is not added after year five*. PacifiCorp also explains that, in real (inflation-adjusted) terms, the fixed generation costs are held constant through year 10. As we did in previous orders, we find it reasonable to assume that fixed generation costs will increase at the rate of inflation after year five. [Emphasis added]

In UE 307 the Commission again declined to accept my recommendation, although the Commission also ordered:

> For the next TAM filing, we direct PacifiCorp, dba Pacific Power, to include a historical time series of fixed generation costs included in its direct access opt-out charge, broken down by its components (e.g., capital, O&M) as a check on the reasonableness of its forecasts.[27]

Q. You stated that Calpine Solutions has appealed this decision in the Oregon Court of Appeals. If this issue is readdressed by the Commission, have you estimated how much Schedule 200 should decline from Year 6 through Year 10 in the calculation of the Consumer Opt-Out charge?

A. Yes. As I testified in UE 296 and UE 307, the Schedule 200 entry should decline by approximately 2.36% per year from Years 6 through 10. The return component is approximately 28.2% of the Schedule 200 revenue requirement and annual depreciation and amortization of production plant is approximately 8.38% of production rate base. This means that, absent new additions to rate base, the existing production rate base (and return on that rate base) shrinks by about 8.38% per year. Since the return component is about 28.2% of the Schedule 200 revenue requirement, the annual reduction in return revenues of 8.36% translates into a reduction in overall Schedule 200 revenue requirement of 2.36% per year (i.e., 8.38% x 28.2%). As PacifiCorp has not conducted an Oregon general rate case since I made these calculations, these calculations remain applicable today.

Q. Have you calculated the effects of your two recommended refinements to the Consumer Opt-Out charge related to the inclusion of Schedule 200 costs

[27] UE 307, Order No. 16-482 at 25.

projected for years six through 10 on the sample Schedule 296 calculation provided by PacifiCorp in this case?

A. Yes. As shown in Exhibit Calpine Solutions/104, Higgins/2-3, these refinements reduce the sample Consumer Opt-Out charge from $17.61/MWh to $14.22/MWh for Schedule 30-S and from $14.18/MWh to $10.99/MWh for Schedule 48-P (excluding REC credits).

So, for example, with this change, a participating customer on Schedule 48-P using 100,000 MWh of energy per year (roughly the size of a 15 MW customer) would pay PacifiCorp $3,663,000 per year in Year 1 transition costs[28] (inclusive of Schedule 200 and the Consumer Opt-Out charge) or $319,000 less than under the Company's proposal.

Q. Has PacifiCorp presented a historical time series of fixed generation costs included in its direct access opt-out charge as required by the Commission in Order No. 16-482?

A. Yes. This information is presented in Exhibit PAC/110, attached to Mr. Wilding's testimony.

Q. Does the time series information provided by PacifiCorp support the contention that the Company's fixed generation cost, exclusive of incremental generation investment, is growing at the rate of inflation?

A. No. The time series information presented in Exhibit PAC/110 makes no attempt to exclude incremental generation investment. Indeed, incremental generation investment is the primary driver behind the growth in PacifiCorp's fixed generation costs over the 2006-15 period covered in Exhibit PAC/110. If

[28] ($25.64/MWh + $10.99/MWh) x 100,000 MWh = $3,663,000.

the incremental generation investment is removed from the analysis, then the results are significantly different, as I will discuss below.

Q. Before removing the incremental generation investment from the analysis, do you have any observations regarding the data provided by the Company?

A. Yes. Even prior to excluding incremental generation investment from the analysis, I note that from 2010 to 2015, covering the most recent five years of analysis, the compound annual growth rate of the Company's fixed generation cost was only 1.4% per year, which is materially less than the inflation rate of 2.5% being used by the Company to escalate the fixed generation costs included in the Consumer Opt-Out Charge in years 6-10.[29]

Q. Please describe the rate of change of the Company's fixed generation costs when incremental generation investment is excluded.

A. In discovery, I asked PacifiCorp to restate its analysis by excluding all additions to rate base and the associated incremental costs. PacifiCorp objected to this request as overly broad and burdensome. Instead, I obtained from PacifiCorp various components of incremental generation cost since 2006, to prepare my own calculation. Specifically, I obtained data covering the incremental generation investment that has occurred since 2006, along with the depreciation expense and accumulated depreciation. I also requested associated accumulated deferred income taxes ("ADIT"), but this was not provided in time for me to use it in this testimony. However, based on the information that the Company was able to provide, I have recalculated PacifiCorp's fixed generation cost per MWh,

[29] The inflation rate used by the Company can be derived by calculating the growth rate embedded in the Schedule 200 column for 2022-2027 in Exhibit Calpine Solutions/103/Higgins/3.

excluding incremental generation investment. The results of this analysis are presented in Exhibit Calpine Solutions/105.

As shown in Exhibit Calpine Solutions/105, when incremental generation capital additions (excluding environmental upgrades) are removed from the analysis, PacifiCorp's Oregon-allocated fixed generation have declined from \$22.20/MWh to \$21.31/MWh from 2008 to 2015. If environmental upgrades are also excluded, the decline over that period goes from \$21.66/MWh to \$17.52/MWh, a decline of 19% over 7 years. These results are much more consistent with my contention that fixed generation costs attributed to direct access customers for the purpose of calculating the Consumer Opt-Out Charge for years 6-10 should decline over that period, rather than increase at the rate of inflation as occurs in the Company's calculation.

Q. PacifiCorp's time series begins in 2006. Do you have any concerns about using 2006 as a reference point in this analysis?

A. Yes. The Company notes that the 2006 data are based on the March 2006 Results of Operations whereas the data for all other years are based on December Results of Operations. This suggests that the 2006 data are nearly two years removed from the rest of the time series and therefore are not directly comparable. The jump in average fixed generation costs of 43% from 2006 to 2007 as reported in the Company's table is a further indication that 2006 is an anomalous entry that is not useful as a point of reference in this analysis.

Q. What are the implications regarding the absence of incremental ADIT from your calculations?

A. If incremental ADIT were included that would increase my calculation of net fixed generation cost per MWH somewhat and I will reserve the right to supplement my calculation after PacifiCorp provides me with the necessary ADIT information. However, my calculations also do not include incremental operations and maintenance expense or property taxes associated with incremental generation plant, in deference to the burdensomeness cited by PacifiCorp; yet inclusion of these items in the analysis would *reduce* the net fixed generation cost, i.e., offsetting to some extent the effect of excluding ADIT.

Q. Please summarize your recommendations concerning the Schedule 296 calculation in this proceeding.

A. First, the transition adjustment component of Schedule 296 and the Consumer Opt-Out charge should be adjusted to reflect the value of freed-up RECs. The REC valuation should be updated annually for Year 1 through Year 5 and should reflect the then-current proportion of RPS-eligible resources that is required. In addition, for Years 6 through 10, a projected value for freed-up RECs should be included as a credit in the calculation of the Consumer Opt-Out charge, combined with the relevant RPS requirement percentage. These valuations could be made either using the price of RECs sold by PacifiCorp or the price of RECs purchased by PacifiCorp through the RFP issued by the Company in 2016. In the alternative, PacifiCorp could agree or be required to transfer to the direct access customer's ESS the customer's pro rata share of RECs, or simply retire those RECs on the customer's or the ESS's behalf, thereby passing on that value to the direct access customer. This transfer should occur during the same

10-year-period over which the Consumer Opt-Out charge is calculated for a given customer.

Second, if the Commission readdresses the escalation of Schedule 200 costs, the appropriate adjustments are presented in my testimony and exhibits in this docket.

Third, the time series analysis presented by the Company does <u>not</u> support the use of an inflation escalator as being indicative of fixed generation costs over time applicable to a discrete set of generation assets, i.e., a capped resource portfolio that is not subject to new generation investment. Rather, when the effects of incremental generation investment are excluded, the analysis supports my contention that unit fixed generation costs applied to a discrete set of assets declines over time due to the effects of accumulated depreciation on the return on rate base.

Q. Does this conclude your opening testimony?

A. Yes, it does.

Docket No. UE 323

EXHIBIT

Calpine Solutions 101

Status Report

Oregon Electric Industry Restructuring

(Number of Participating Customers as of June, 2016)

Status Report

Oregon Electric Industry Restructuring
(Number of Participating Customers as of June, 2016)

Portfolio Options*	PGE	PP&L
Fixed Renewable	9,513	11,871
Renewable Usage	128,569	38,126
Renewable Solar	2,633	
Habitat		5,066
Habitat Rider***	8,498	
Time-of-use	3,363	1,541
Eligible Customers	841,403	575,859**

* Available to residential and small nonresidential customers. Customers may, in certain circumstances, choose more than one option.
** As of January 1, 2016.
*** Habitat Rider is available to existing renewable customers only, and should not be included in calculation of total renewable enrollment numbers.

Direct Access and Standard Offer Service

Certified Electricity Service Suppliers:
Registered Electricity Service Aggregators:

Nonresidential Customer Choices (based on load):

	Cost of Service	Market Options	Direct Access
PGE	83.1%	1.2%	15.7%
PP&L	96.3%	0.2%	3.5%

This report reflects prior month results.

Produced by the Oregon Public Utility Commission
Energy Resources & Planning
(503) 378-6917

Docket No. UE 323

EXHIBIT

Calpine Solutions 102

PacifiCorp Responses to Data Requests Referenced in Testimony

One-Year Option - Transition Adjustments (cents/kWh)

Initial Filing UE323 - Sample Calculations

REC credit
cents/kWh
$0.013

	2018			
	30/730 Secondary		48/748 Primary	
	HLH	**LLH**	**HLH**	**LLH**
Jan-18	-1.249	-0.937	-1.428	-1.164
Feb-18	-0.726	-0.789	-0.934	-1.008
Mar-18	-0.605	-0.133	-0.810	-0.324
Apr-18	0.160	0.631	-0.093	0.466
May-18	0.405	0.700	0.176	0.484
Jun-18	0.234	0.207	0.042	-0.004
Jul-18	-1.812	-0.671	-1.998	-0.879
Aug-18	-1.022	-0.864	-1.254	-1.145
Sep-18	-1.024	-0.677	-1.291	-0.900
Oct-18	-0.599	-0.366	-0.846	-0.570
Nov-18	-0.695	-0.563	-0.276	-0.718
Dec-18	-0.795	-0.761	-0.978	-0.940
Annual Average*			-0.807	-0.558

Source File Name: 15-M - ORTAM18w_Transition Adjustment Summary
Source Directory OR UE 323 TAM Support Set 3 Non-Confidential Attachement
*Higgins Calculation

Calpine Energy Solutions Data Request 1.1

Section 15 of the TAM Stipulation dated September 4, 2008 in UE-199 provides that in the calculation of the Schedule 294 transition adjustment, monthly thermal generation that is backed down for assumed direct access load will be priced at the simple monthly average of the COB price, the Mid-Columbia price, and the avoided cost of thermal generation as determined by GRID. Section 15 further provides that the monthly COB and Mid-Columbia prices will be applied to the heavy load hours or light load hours separately. Please confirm that PacifiCorp has used the calculation described above in calculating the Sample Schedule 294 Transition Adjustments for Schedules 30 and 48 filed in UE 323.

Response to Calpine Energy Solutions Data Request 1.1

PacifiCorp confirms that the calculation of the Sample Schedule 294 Transition Adjustment for Schedule 30 and Schedule 48 is consistent with the method set forth in Section 15 of the Transition Adjustment Mechanism (TAM) Stipulation in Docket UE 199. For details on the calculations, please refer to the confidential work papers provided with the Company's response to TAM Support Set 3; specifically those work papers beginning with "15-M."

Calpine Energy Solutions Data Request 1.3

Please provide the following information regarding PacifiCorp's Oregon retail load in 2016, expressed in MWH, and indicate whether PacifiCorp's sales to Georgia Pacific-Camas are included in (a) and (b):

(a) Total Oregon retail load excluding direct access.

(b) Total Oregon retail load that was eligible for direct access.

(c) Direct access load differentiated into the categories of (i) annual, (ii) three-year opt out, and (iii) five-year opt-out.

1st Supplemental Response to Calpine Energy Solutions Data Request 1.3

Further to the Company's response to Calpine Energy Solutions Data Request 1.3 provided on May 9, 2017, the Company provides the following supplemental response to subpart (c):

Following discussions with counsel for Calpine Energy Solutions, PacifiCorp agreed to provide a non-confidential response to Calpine Energy Solutions Data Request 1.3(c)(i) and agreed to remove the confidential classification to Calpine Energy Solutions Data Request 1.3(c)(iii).

(c) Please refer to the Company's supplemental responses to subparts (i) and (iii) below:

i. Rounded to the nearest 5 average megawatts (aMW), the enrolled annual load is 10 aMW.

iii. PacifiCorp continues to object to this request as not reasonably calculated to lead to the discovery of admissible evidence. The load associated with a specific customer is not relevant to this proceeding. Without waiving this objection, the Company responds as follows:

Rounded to the nearest 5 average aMW, the enrolled load is 15 aMW. PacifiCorp confirms that only one customer elected to participate in the five-year opt-out program.

Docket No. UE 323

EXHIBIT

Calpine Solutions 103

Non-Confidential Excerpt from PacifiCorp Response to Calpine Solutions Data Request 1.7

Note: This exhibit contains excerpts from data responses originally designated as confidential that PacifiCorp has agreed may be presented as non-confidential.

Calpine Energy Solutions Data Request 1.7

Please provide sample calculations and supporting work papers for Schedule 296 (transition adjustments and opt-out charge) that would be applicable to Schedule 30-Secondary customers and Schedule 48-Primary customers.

Response to Calpine Energy Solutions Data Request 1.7

Please refer to Confidential Attachment Calpine Energy Solutions 1.7 -1 and Confidential Attachment Calpine Energy Solutions 1.7 -2, which provide the sample calculation for Schedule 296.

The confidential attachments are designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

Schedule 30
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=26.20-8.59
2018	$26.74	$27.48	($0.73)	-	$30.51	-	$17.61
2019	$26.59	$27.27	($0.68)	-	$31.24	-	$17.61
2020	$26.56	$28.78	($2.22)	-	$31.99	-	$17.61
2021	$26.99	$30.91	($3.92)	-	$32.76	-	$17.61
2022	$27.36	$32.58	($5.22)	-	$33.55	-	$17.61
2023	$28.52	$35.60		($7.08)		$34.36	
2024	$29.18	$39.81		($10.63)		$35.22	
2025	$29.88	$42.77		($12.89)		$36.10	
2026	$30.13	$44.09		($13.96)		$37.00	
2027	$30.65	$46.44		($15.79)		$37.93	
10-Year Net Present Value (1)				($35.63)		$108.66	$73.03
5-year Nominal Levelized Payment				($8.59)		$26.20	$17.61

Notes:
(1) 2018 through 2027 using a 6.57% Discount Rate
(2) Losses at 8.01%

Schedule 47/48
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=24.58-10.41
2018	$24.49	$27.48	($2.99)	-	$28.63	-	$14.18
2019	$24.35	$27.27	($2.92)	-	$29.32	-	$14.18
2020	$24.32	$28.78	($4.46)	-	$30.02	-	$14.18
2021	$24.71	$30.91	($6.20)	-	$30.74	-	$14.18
2022	$25.05	$32.58	($7.53)	-	$31.48	-	$14.18
2023	$26.11	$35.60		($9.49)		$32.24	
2024	$26.72	$39.81		($13.09)		$33.05	
2025	$27.36	$42.77		($15.41)		$33.88	
2026	$27.59	$44.09		($16.50)		$34.73	
2027	$28.07	$46.44		($18.37)		$35.60	
10-Year Net Present Value (1)				($43.16)		$101.97	$58.81
5-year Nominal Levelized Payment				($10.41)		$24.58	$14.18

Notes:
(1) 2018 through 2027 using a 6.57% Discount Rate
(2) Losses at 8.01%

Docket No. UE 323

EXHIBIT

Calpine Solutions 104

Calpine Solutions Adjustment to Sample Schedule 296 Consumer Opt-Out Charges for Schedules 30 - S and 48 - P

Note: This exhibit contains material originally designated as confidential that PacifiCorp has agreed may be presented as non-confidential.

Derivation of Return Component in Sch. 200
in PacifiCorp 2013 Rate Case, Docket UE-263

Line			Source
1	Approved Rate of Return on Rate Base	7.621%	Docket UE-263 Order13-474, Appendix A (Stipulation, p. 4 of 39).
2	Oregon Production Rate Base Included in Sch. 200	$ 1,662,452,363	Docket UE-296 Exhibit Noble Solutions/102, Higgins/11.
3	Return on Production Rate Base Included in Sch. 200	$ 126,695,495	= Ln. 1 x Ln. 2
4	Tax Gross-Up Factor	1.6611	Docket UE-296 Exhibit Noble Solutions/102, Higgins/14.
5	Revenue Requirement Impact of Return on Production Rate Base	$ 210,456,137	= Ln. 3 x Ln. 4
6	Total Unbundled Oregon Production Revenue Requirement	$ 747,123,482	Docket UE-296 Exhibit Noble Solutions/102, Higgins/11-13.
7	Percentage of Return Component in Production Revenue Requirement	28.2%	= Ln. 5 ÷ Ln. 6
8	Annual Oregon Production Depreciation/Amortization Exp.	$ 139,238,810	Docket UE-296 Exhibit Noble Solutions/102, Higgins/15-16.
9	Annual Deprecation/Amortization Exp. as Pct. of Rate Base	8.38%	= Ln. 8 ÷ Ln. 2
10	Annual Depreciation Impact on Production Return Component	**2.36%**	= Ln. 7 x Ln. 9

Calpine Solutions
Schedule 30 (Sec.)
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates*	NPC Impact of 50 aMW Leaving System*	Transition Adjustment		Schedule 200 - Base Supply*		Consumer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=22.81-8.59
2018	$26.74	$27.48	($0.73)	-	$30.51	-	$14.22
2019	$26.59	$27.27	($0.68)	-	$31.24	-	$14.22
2020	$26.56	$28.78	($2.22)	-	$31.99	-	$14.22
2021	$26.99	$30.91	($3.92)	-	$32.76	-	$14.22
2022	$27.36	$32.58	($5.22)	-	$33.55	-	$14.22
2023	$28.52	$35.60		($7.08)		$32.76	
2024	$29.18	$39.81		($10.63)		$31.99	
2025	$29.88	$42.77		($12.89)		$31.24	
2026	$30.13	$44.09		($13.96)		$30.50	
2027	$30.65	$46.44		($15.79)		$29.78	
10-Year Net Present Value (1)				($35.63)		$94.59	$58.97
5-year Nominal Levelized Payment				($8.59)		$22.81	$14.22

Notes:
(1) 2018 through 2027 using a 6.57% Discount Rate.
(2) Losses at 8.01%

* Data Sources:

For Schedule 201 (Cols. a & b), see Pacificorp Response to Calpine Solutions DR No. 1.7 (Included in Calpine Solutions/103, Higgins/1-3).

For Schedule 200 (Col. d), for 2018 - 2022, see PacifiCorp Response to Calpine Solutions DR No. 1.7 (Included in Calpine Solutions/103, Higgins/1-3).

Calpine Solutions
Schedule 47/48 (Pri.)
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates*	NPC Impact of 50 aMW Leaving System*	Transition Adjustment		Schedule 200 - Base Supply*		Consumer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=21.39-10.41
2018	$24.49	$27.48	($2.99)	-	$28.63	-	$10.99
2019	$24.35	$27.27	($2.92)	-	$29.32	-	$10.99
2020	$24.32	$28.78	($4.46)	-	$30.02	-	$10.99
2021	$24.71	$30.91	($6.20)	-	$30.74	-	$10.99
2022	$25.05	$32.58	($7.53)	-	$31.48	-	$10.99
2023	$26.11	$35.60		($9.49)		$30.74	
2024	$26.72	$39.81		($13.09)		$30.01	
2025	$27.36	$42.77		($15.41)		$29.30	
2026	$27.59	$44.09		($16.50)		$28.61	
2027	$28.07	$46.44		($18.37)		$27.94	
10-Year Net Present Value (1)				($43.16)		$88.74	$45.58
5-year Nominal Levelized Payment				($10.41)		$21.39	$10.99

Notes:
(1) 2018 through 2027 using a 6.57% Discount Rate.
(2) Losses at 8.01%

* Data Sources:

For Schedule 201 (Cols. a & b), see Pacificorp Response to Calpine Solutions DR No. 1.7 (Included in Calpine Solutions/103, Higgins/1-3).

For Schedule 200 (Col. d), for 2017 - 2021, see PacifiCorp Response to Calpine Solutions DR No. 1.7 (Included in Calpine Solutions/103, Higgins/1-3).

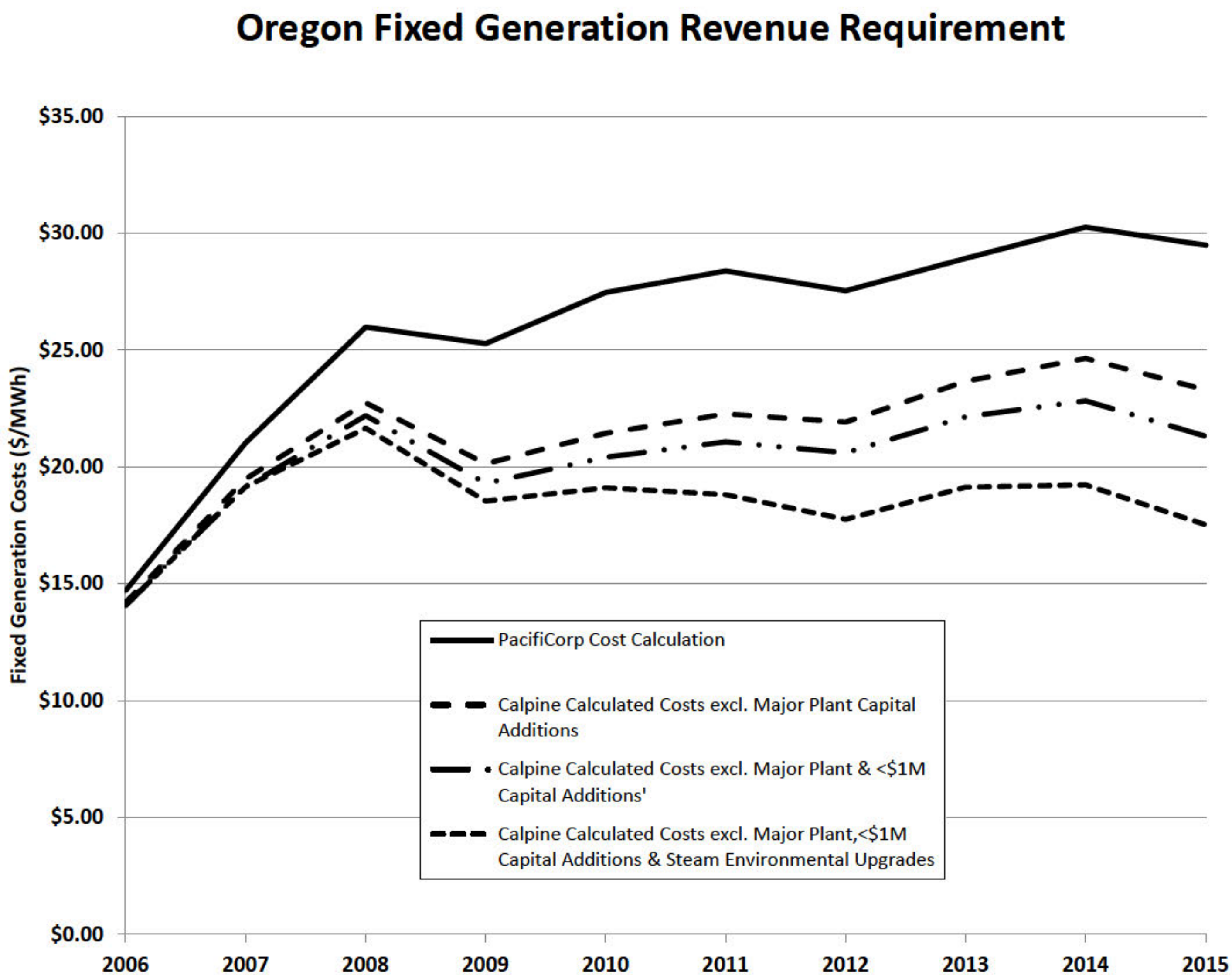
Docket No. UE 323

ERRATA

EXHIBIT

Calpine Solutions 105

Oregon Fixed Generation Costs 2006-2015 with Incremental Generation Investment Removed


Oregon Fixed Generation Revenue Requirement
Fixed Generation Costs ($/MWh)
$35.00
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
PacifiCorp Cost Calculation
Calpine Calculated Costs excl. Major Plant Capital Additions
Calpine Calculated Costs excl. Major Plant & <$1M Capital Additions'
Calpine Calculated Costs excl. Major Plant,<$1M Capital Additions & Steam Environmental Upgrades

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

PacifiCorp Calculation:	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)
Revenue Requirement ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656
Revenue Requirement ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**
Calpine Removal of Major Plant Capital Additions:[1]										
Gross Plant in Service	(49,761,778)	(176,568,828)	(369,536,398)	(559,776,664)	(655,685,388)	(691,632,401)	(679,219,846)	(660,056,733)	(749,957,135)	(839,282,324)
Accumulated Depreciation	1,705,854	7,651,247	20,686,488	40,038,359	61,385,631	86,513,269	109,156,467	129,609,175	155,074,318	183,020,532
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	(48,055,924)	(168,917,581)	(348,849,910)	(519,738,305)	(594,299,757)	(605,119,131)	(570,063,379)	(530,447,557)	(594,882,817)	(656,261,792)
Return On Rate Base	(4,280,575)	(13,785,364)	(28,166,881)	(42,769,265)	(49,511,113)	(48,609,220)	(43,986,090)	(40,669,493)	(45,104,360)	(49,420,418)
Operating & Maintenance Expense										
Depreciation Expense	(1,705,854)	(5,995,304)	(12,827,315)	(19,865,901)	(23,216,345)	(24,649,246)	(24,207,316)	(23,524,120)	(23,850,818)	(26,559,190)
Amortization Expense										
Taxes Other Than Income										
Federal Income Taxes	(1,152,462)	(3,711,444)	(7,583,391)	(11,514,802)	(13,329,915)	(13,087,098)	(11,842,409)	(10,949,479)	(12,143,482)	(13,305,497)
State Income Taxes	(156,601)	(504,324)	(1,030,457)	(1,564,670)	(1,811,314)	(1,778,319)	(1,609,187)	(1,487,852)	(1,650,097)	(1,807,996)
Deferred Income Taxes										
Misc Revenue & Expenses										
Revenue Credits										
Revenue Requirement ($)	(7,295,492)	(23,996,436)	(49,608,044)	(75,714,639)	(87,868,687)	(88,123,883)	(81,645,002)	(76,630,945)	(82,748,757)	(91,093,102)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656
Revenue Requirement ($/MWh)	(0.49)	(1.54)	(3.23)	(5.15)	(6.03)	(6.12)	(5.62)	(5.26)	(5.61)	(6.20)
Revenue Requirement excl. Major Plant Additions ($)	209,896,920	302,885,523	349,056,354	296,297,733	312,502,503	320,711,833	318,614,966	344,446,638	363,416,250	342,433,673
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656
Revenue Requirement excl. Major Plant Additions ($/MWh)	**14.20**	**19.49**	**22.75**	**20.14**	**21.44**	**22.27**	**21.92**	**23.66**	**24.65**	**23.29**

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Calpine Removal of Capital Additions <$1,000,000:[2]										
Gross Plant in Service	(14,277,622)	(39,179,195)	(65,870,707)	(94,527,462)	(114,930,142)	(138,916,099)	(160,366,039)	(174,827,310)	(196,239,217)	(221,821,445)
Accumulated Depreciation	444,937	1,635,735	3,619,353	6,315,656	9,409,760	13,569,560	18,029,574	24,595,470	35,892,420	48,332,489
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	(13,832,685)	(37,543,460)	(62,251,354)	(88,211,805)	(105,520,381)	(125,346,540)	(142,336,465)	(150,231,840)	(160,346,797)	(173,488,956)
Return On Rate Base	(1,232,145)	(3,063,922)	(5,026,306)	(7,258,949)	(8,790,903)	(10,069,088)	(10,982,682)	(11,518,298)	(12,157,587)	(13,064,751)
Operating & Maintenance Expense										
Depreciation Expense	(444,937)	(1,203,817)	(1,939,166)	(2,786,239)	(3,388,932)	(4,086,467)	(4,705,345)	(7,073,206)	(10,990,606)	(12,119,038)
Amortization Expense										
Taxes Other Than Income										
Federal Income Taxes	(331,731)	(824,902)	(1,353,236)	(1,954,333)	(2,366,782)	(2,710,908)	(2,956,876)	(3,101,080)	(3,273,197)	(3,517,433)
State Income Taxes	(45,077)	(112,090)	(183,882)	(265,561)	(321,606)	(368,367)	(401,790)	(421,385)	(444,773)	(477,961)
Deferred Income Taxes										
Misc Revenue & Expenses										
Revenue Credits										
Revenue Requirement ($)	(2,053,889)	(5,204,731)	(8,502,591)	(12,265,082)	(14,868,223)	(17,234,830)	(19,046,693)	(22,113,969)	(26,866,162)	(29,179,183)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656
Revenue Requirement ($/MWh)	(0.14)	(0.33)	(0.55)	(0.83)	(1.02)	(1.20)	(1.31)	(1.52)	(1.82)	(1.98)
Revenue Requirement excl. Major Plant & <$1M Additions ($)	207,843,031	297,680,792	340,553,763	284,032,650	297,634,281	303,477,003	299,568,272	322,332,669	336,550,087	313,254,490
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656
Rev. Req. excl. Major & Minor Plant Additions ($/MWh)	**14.06**	**19.15**	**22.20**	**19.30**	**20.42**	**21.07**	**20.61**	**22.15**	**22.83**	**21.31**
Calpine Removal of Steam Plant Environmental Upgrades:[3]										
Gross Plant in Service	0	0	(64,819,100)	(88,283,909)	(145,698,106)	(255,630,466)	(338,727,313)	(366,898,039)	(382,499,203)	(417,759,012)
Accumulated Depreciation	0	0	3,691,955	5,950,644	9,923,502	17,610,867	27,296,949	37,382,240	58,742,673	81,840,452
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	(61,127,145)	(82,333,265)	(135,774,604)	(238,019,599)	(311,430,364)	(329,515,799)	(323,756,530)	(335,918,560)
Return On Rate Base	0	0	(4,935,535)	(6,775,204)	(11,311,382)	(19,120,114)	(24,029,967)	(25,264,025)	(24,547,408)	(25,296,667)
Operating & Maintenance Expense										
Depreciation Expense	0	0	(1,780,096)	(2,350,429)	(4,250,647)	(7,610,028)	(10,004,478)	(10,853,365)	(20,894,824)	(22,572,370)
Amortization Expense										
Taxes Other Than Income										
Federal Income Taxes	0	0	(1,328,798)	(1,824,093)	(3,045,372)	(5,147,723)	(6,469,606)	(6,801,853)	(6,608,918)	(6,810,641)
State Income Taxes	0	0	(180,562)	(247,864)	(413,815)	(699,490)	(879,112)	(924,259)	(898,042)	(925,453)
Deferred Income Taxes										
Misc Revenue & Expenses										
Revenue Credits										
Revenue Requirement ($)	0	0	(8,224,991)	(11,197,591)	(19,021,217)	(32,577,356)	(41,383,164)	(43,843,502)	(52,949,192)	(55,605,130)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656
Revenue Requirement ($/MWh)	0.00	0.00	(0.54)	(0.76)	(1.30)	(2.26)	(2.85)	(3.01)	(3.59)	(3.78)
Rev. Req. excl. Major & Minor Plant Adds. & Env Upgrades ($)	207,843,031	297,680,792	332,328,772	272,835,060	278,613,064	270,899,647	258,185,109	278,489,167	283,600,895	257,649,360
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656
Rev. Req. excl. Major/Minor Plant Adds. & Env. Upgrades ($/MWh)	**14.06**	**19.15**	**21.66**	**18.54**	**19.11**	**18.81**	**17.76**	**19.13**	**19.23**	**17.52**

Notes: 1. NA = Data not available at the time of filing.
2. Federal and state income tax calculation assumes 50%/50% debt and equity capital structure components

Data Sources:
1. PacifiCorp Responses to Calpine Solutions Data Request Nos. 1.8 & 5.1.
2. PacifiCorp Response to Calpine Solutions Data Request No. 3.1.
3. PacifiCorp Response to Calpine Solutions Data Request No. 5.1.